PG&E's Comments on Draft NEM Cost-Effectiveness Evaluation Study

October 10, 2013

Introduction

PG&E appreciates this opportunity to provide comments on "Draft California Net Energy Metering Evaluation", the NEM cost effectiveness evaluation ("Draft Report" or "DR"). PG&E generally supports the methodology, scope and results of the report. Indeed, this report should serve as valuable foundation for the CPUC as it initiates NEM reform proceedings in implementation of AB 327.

The DR has many strengths, including detailed bill calculations that capture a wide range of sub-hourly load and generation profiles and rate schedules, the broad inclusion of scenario analyses, and analysis of income variation at the census block group level.

The primary focus of these comments is on certain areas of weakness in the DR which should be corrected prior to the release of the final report. Where an amendment is impossible, a detailed caveat should be included to prevent potential misinterpretation of the DR results. The main points addressed in these comments are:

- Clarify in the Cost of Service Analysis that DG adoption shifts costs to other customers
- Eliminate or clarify the significance of the Export Only case
- Adjust a limited number of important Cost-Benefit study inputs and assumptions

Clarify in the Cost of Service Analysis that DG adoption shifts costs to other customers

The Cost of Service ("COS") section of the DR needs to be modified to make it clear that the results are entirely consistent with the findings in the Cost-Benefit portion of the DR study that NEM adoption places a significant burden on non-adopting customers. Without additional modification, it is possible to conclude that since, on average, NEM customers appear to contribute revenues that generally match their cost of service even after installing DG, there is no need to address the cost-shift issue. There are four basic issues that need to be addressed to avoid a misinterpretation of the results. First, the report should be revised to reflect the difference between "cost-of-service" and a customer's equitable contribution. Long-standing policies to cross-subsidize certain groups like CARE customers mean that non-subsidized customers should expect to contribute *more* than 100% of their "cost"; so the benchmark for contributing an equitable share is higher than 100%.

Second, the report does not reflect the effect on the contribution of the non-participant after the NEM customer adopts DG. The DG customer's reduction in contribution needs to be recovered from the utilities' other customers.[1]

[1] For example, consider two groups of customers, both of whom have the pre-NEM characteristics of the PG&E Residential customers in Table 5, but only one of which can install DG. Both groups start with a COS of 171%. When the first group goes on NEM, their COS goes to 93%. However, the other non-adopting group would see their contribution *increase* as a result of the first group's adoption. As more customers participate in NEM, the contribution of the remaining customers would be significantly higher than 171%.

Third, the analysis understates the costs (the denominators in the ratios) for the DG customers. Also, additional distribution cost associated with DG and the integration costs associated with higher levels of DG penetration are excluded from the analysis. Further, while the DR acknowledges that characteristics such as higher incidence of single family dwellings among residential customers were not evaluated, there should be a more direct means of reflecting the significant cost differential between customers in single-family dwellings versus those in apartments.

Fourth, the revenue collected from NEM customers is highly skewed and use of the average can be misleading[2]. E3 should calculate the COS contributions from NEM customers using the median contribution rather than the average.

Cost of Service vs Equitable Share. The current residential rate design, with its steeply inverted tiers, creates a fundamental cost-shift that affects all higher-usage, non-CARE residential customers. The correct interpretation of Table 5 is that it illustrates how the current NEM program, after being overlaid on the state's currently steeply-inverted rates, has created a group of primarily high-energy-use residential DG customers who are able to exempt themselves from the existing cost-shift that other similarly situated customers may not be able to avoid. As shown in Table 2, the net cost of just the residential portion of this special exemption will eventually approach $800 million per year, putting much additional upward pressure on upper-tier rates for large numbers of other residential customers unable to avail themselves of this "opt-out" alternative.

Regulatory Costs. At the workshop, E3 indicated that regulatory costs were allocated to the customers based on their net load. While these customers actually contribute to the recovery of these costs on a *net* basis, the costs (the denominators in the ratios) should be based on the customer's gross (pre-DG) usage, since these utility costs are not reduced when the DG is installed.

Eliminate or Clarify the Significance of the Export Only Case

Inclusion of **the Export Only** scenario in its current form is misleading. As the DR recognizes (page 22), and as directed by the Legislature, E3 should measure the NEM program cost shift based on the total output from the NEM generators. Clearly, the cross-subsidies involved from NEM customers result from crediting all output against a volumetric retail rate that is distorted by unavoidable and fixed costs. It makes no difference whether the customer's DG actually generates as a net exporter to the grid; the cross-subsidies still exist.

PG&E understands that some parties want to know the cost shift associated with just the power that is exported onto the grid. E3 has produced this estimate. However, its current position in the report is premised on a fictional, hypothetical scenario where the cost-shift associated with the NEM program could be construed as only that associated with the exports, since the cost-shift tied to the power consumed directly on-site is presumed to have existed with or without the

[2] Using simple average residential revenue as the cost of service, PG&E finds that approximately 75% of NEM customers contribute less than the "cost of service". The very high revenues collected from a few NEM customers disguises this fact when the average is used.

compensation for exports.[3] This construct should be eliminated as it runs counter to the direction provided by the legislature in AB 2514, and ignores the basic fact that all of the output from customer generation causes cost shifts. The final report might still include the estimate of the cost shift from exports only, but it should be represented as just that, and not as a plausible answer to the impact of the current NEM program, which includes exemption from standby charges and other means of recovering appropriately incurred costs.

In addition, the DR states that in the export-only calculations, the at-site customer usage is treated like energy efficiency. This mischaracterization should be eliminated. At-site generation that meets the customer's own load is not the same as energy efficiency for several reasons - chiefly, energy efficiency is reliable and predictable and its effect on the distribution grid is universally a drop in load, and usually during the hours when the system or distribution circuits peak (after 5 pm). Customer generation, especially solar, is only intermittently available and the grid must stand ready to meet customer load instantaneously when it fails. When energy efficiency equipment fails, demand on the grid falls.

Adjust Cost-Benefit Study Inputs and Assumptions

The method and results from the Cost-Benefit analysis of total generation output were generally sound, however several key inputs and assumptions discussed below should be revised.

RPS Premium. The avoided RPS procurement costs are overstated in the analysis. The cost of going-forward RPS procurement starts at \$128/MWh in 2013 based on values in the outdated 2011"Padilla Report".[4] That report reflects historical market prices that were more expensive than current ones. The 2013 Padilla report shows that the IOU-wide cost of contracts approved in 2012 was \$97/MWh[5], and recent solicitations in the state have suggested even lower numbers.

The incremental transmission cost associated with the marginal renewable resource is based on an outdated standardized planning assumption from the CPUC's 2010 LTPP. More recent renewable procurement has focused on smaller projects that may not trigger the same level of transmission upgrades. This outdated assumption alone leads to an overstatement of the RPS premium by over \$25/MWh.

In addition, while PG&E appreciates that the analysis appropriately attributes renewable value to just the amount of renewable procurement that the IOUs can avoid since the load is no longer in the denominator, no consideration is given to the reality that California is on track to meet its interim requirement of 25% renewables by 2016, and is well positioned to meet 33% by 2020[6]. Therefore, the annual savings in years prior to 2020 should be substantially discounted.

[3] Ironically, the solar community itself has repeatedly claimed that without NEM, there would likely be little, if any, customer-side solar in California.

[4] RPS Report to the Legislature: Cost Reporting in Compliance with SB 836

[5] http://www.cpuc.ca.gov/NR/rdonlyres/F0F6E15A-6A04-41C3-ACBA-8C13726FB5CB/0/PadillaReport2012Final.pdf

[6] CPUC Renewables Portfolio Standard Quarterly Report, 3rd and 4th Quarter 2012.

Generation Capacity. There have been several methodological improvements in the avoided generation capacity calculation (in particular the introduction of an ELCC assessment of solar that declines in value over time and an updated set of RA values through 2012). However, several key assumptions and methodological approaches lead to substantial overstatement of the avoided generation capacity cost. First, the model adopts 2017 as the "resource balance year" (RBY) that determines when new capacity is needed. This assessment comes from an outdated case in the 2010 Long Term Procurement Plan (LTPP) proceeding, with unreasonable adjustments that are not appropriate for this analysis such as the exclusion of all incremental Demand Response and Energy Efficiency past 2013[7]. The 2012 LTPP provides a more updated outlook showing that even without replacing San Onofre Nuclear Generating Station, the system-wide RBY is past 2020.

For PG&E, the generation capacity cost that NEM generation helps avoid should be based on the RBY of system-wide (i.e., not local) non-flexible generation. Furthermore, before the RBY is reached, there will be a need for new capacity with flexible characteristics to accommodate an increasing percentage of renewable generation. Rather than help avoid this capacity, NEM resources actually increase that need. As new flexible generation is procured, this flexible generation also satisfies the need for non-flexible capacity, and the RBY for the type of non-flexible capacity that NEM resources help avoid would be pushed out further than the 2026 year included in the "low" sensitivity.

Finally, E3's approach to value capacity before the RBY artificially inflates the annual capacity value by linearly interpolating between the 2012 value and full value in the RBY. Prior to the RBY, the annual cost of capacity should reflect the much lower going forward fixed costs of an existing unit less the gross margin earned in the energy and ancillary services market. PG&E has developed such an approach in its GRC Phase II testimony using public data.

Deferred Distribution Upgrades. PG&E appreciates the substantial revisions that E3 made in its distribution deferral methodology, particularly the more granular allocation of avoided capacity to the actual hours of peak of the various divisions. While PG&E acknowledges the possibility of customer generation to realize avoided distribution costs, many conditions need to be met in addition to more specific assurance of mapping of location and timing of incremental generation with specific facilities that could be deferred.[8]

Deferred Transmission Upgrades. PG&E agrees with the DR that it is inappropriate to include transmission upgrades as a cost that can be deferred by NEM installations. There is no evidence that any transmission projects will be contemplated to meet load growth, which is the only category of transmission investments that is theoretically deferred using customer generation.

Additional Distribution and Integration Costs. The DR ignores a potentially large amount of incremental distribution upgrade and integration costs. When considering the level of DG penetration at the newly defined NEM cap, these costs can be significant. Recent and ongoing

[7] This assumption is clearly in conflict with Commission policy to continue robust programs in both of these areas.
[8] In PG&E's GRC Phase II study, PG&E provided an assessment of the possibility and conditions required for distributed generation to defer distribution costs.

industry studies indicate that clustered DG can increase integration costs.[9] These additional costs would affect both the "Benefit-Cost" analysis as well as the "Full Cost-to-Serve" study.

Residential /Non-residential Customer Split. The DR projects that 60% of the adoption at the NEM cap comes from the non-residential segment. Currently at least half of all new NEM adopters come from the residential segment, and trends show that this percentage will increase. A more reasonable projection to 2020 would reflect a 50/50 mix. Considering that residential customers create a cost shift of $0.19/kWh ($0.23 for PG&E) versus non-residential customers with $0.06/kWh ($0.08 for PG&E), the DR would have measurably understated the annual cost-shift, to the extent that it is based on an under-forecast of the residential adoption rate.

Other Comments

Societal Benefits. PG&E recognizes that the DR methodology appropriately excluded Societal Benefits. The Legislature directed the CPUC to evaluate the rate impact of the NEM program[10], which can only be measured using the Ratepayer Impact Test methodology employed by E3. Inclusion of societal benefits which have no relationship to rates would inappropriately underestimate the rate impact. There are other means of providing compensation for any Societal Benefits that accrue to a larger group of stakeholders (e.g., tax incentives).

Income Analysis. PG&E appreciates the granularity included in the income analysis, as well as the inclusion of population comparisons. Both features underscore that there is a high correlation between income and the likelihood that a customer takes advantage of the NEM program. PG&E further appreciates that CARE customers are included in the population comparison – it makes no sense to exclude CARE customers and, in fact, over 2,000 of the PG&E NEM customers included in the analysis are on CARE rates. PG&E suggests that E3 check the calculations that support the statement on page 110 to the effect that 78% of NEM customers had incomes higher than the California mean and 34% had incomes higher than the IOU median income. This cannot be true. PG&E's median population income is $66,000 and about 70% of our NEM customers have a higher income. The income analysis would more accurately describe the relationship between income and NEM adoption if E3 were to compare participation rates by population income group for something straightforward like deciles of population.

9 CAISO studies on Resource Adequacy and DG Deliverability (e.g., April 2013) clearly indicate there are many locations (CAISO nodes) where minimal or no deliverability for DG is available

10 http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201120120AB2514